REGULATORY LAW CHAMBERS

ENERGY REGULATORY REPORT

This monthly report summarizes matters under the jurisdiction of the Alberta Energy Regulator ("AER"), the Alberta Utilities Commission ("AUC") and the National Energy Board ("NEB") and proceedings resulting from these energy regulatory tribunals. For further information, please contact a member of the RLC Team.

Regulatory Law Chambers ("RLC") is a Calgary based boutique law firm, specializing in energy and utility regulated matters. RLC works at understanding clients' business objectives and develops legal and business strategies with clients. RLC follows a team approach, including when working with our clients and industry experts. Visit our website to learn more about RLC.

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ALBERTA COURT OF APPEAL

EQUS REA Ltd. v. Alberta (Utilities Commission), 2019 ABCA 277

Electricity - Application for Permission to Appeal Denied

In this decision, the Alberta Court of Appeal ("ABCA") considered EQUS REA Ltd. ("EQUS")'s application for permission to appeal AUC Decision 22164-D01-2018 (the "AUC Decision").

The ABCA did not find that there were errors of law or jurisdiction which would merit an appeal. The ABCA therefore dismissed EQUS' application for permission to appeal the AUC Decision.

FortisAlberta's Application and AUC Decision

Pursuant to section 29(1) of the *Hydro and Electric Energy Act* ("*HEEA*"), FortisAlberta Inc. ("FortisAlberta") applied to the AUC for an alteration of service areas to coincide with its exclusive service areas under certain municipal franchise agreements.

Specifically, FortisAlberta applied to the AUC for the following orders:

(a) confirming the limits of FortisAlberta's exclusive service areas as determined by the applicable franchise agreements;

(b) altering the service area boundaries of affected rural electrification associations ("REA(s)") to prevent overlap with exclusive service areas governed by the franchise agreements; and

(c) approving the transfer of REA facilities and customers coincident to the realignment of service areas.

In the AUC Decision, the AUC granted FortisAlberta's application to alter those REA service areas that "currently overlap with the municipal franchise areas granted to FortisAlberta." As a result, FortisAlberta had the exclusive right to provide electrical distribution services in areas which had been served by the REAs. However, the AUC did not require an immediate transfer of existing REAs and customers in the overlapping service areas, given that there was no bylaw requiring those customers to connect to FortisAlberta. In other words, the existing REAs and customers were "grandfathered." The AUC determined that the existing REA facilities in overlapping areas would eventually transition to FortisAlberta because of the altered service areas.

Legislative Scheme

In Alberta, electrical distribution service in certain geographic regions is provided by two providers: public distribution utilities, such as the respondent FortisAlberta Inc. ("FortisAlberta"); or REAs, which supply electric energy in a rural area to the members of the association.

FortisAlberta entered into municipal franchise agreements with a number of Alberta municipalities, pursuant to section 45 of the *Municipal Government Act* and sections 139 and 140 of the *Electric Utilities Act*. The franchise agreements granted FortisAlberta the exclusive right to provide electric distribution service within the municipalities' corporate limits and were based on a standard municipal franchise agreement template that was approved by the AUC in Decision 2012-255, pursuant to section 45(3)(b) of the *Municipal Government Act*.

As a result of the expansion of the corporate boundaries of some municipalities through annexation, the service areas governed by some of FortisAlberta's municipal franchise agreements now overlapped with existing REA service areas.

Section 29(1) of the *HEEA* authorizes the AUC to alter the boundaries of a service area when the AUC considers it is in the public interest to do so.

Grounds for Permission to Appeal

EQUS, one of the REAs affected by the AUC Decision, applied for permission to appeal, submitting that the AUC made three errors of law or jurisdiction:

(a) the AUC erred in law by failing to consider and interpret relevant sections of the *Municipal Government Act* and the *Roles, Relationships and Responsibilities Regulation*, enacted pursuant to the *Electric Utilities Act*;

(b) the AUC erred in law by failing to give effect to the principle of statutory coherence; and

(c) the AUC erred in jurisdiction by using its public interest discretion and service area orders to alter express rights and powers conferred on parties in other related legislation.

Test for Permission to Appeal

The ABCA explained that, under section 29 of the *Alberta Utilities Commission Act*, it may grant permission to appeal if the applicant established that there was an error of law or jurisdiction that merited an appeal to the ABCA. The applicant must demonstrate that the question of law or jurisdiction raised a "serious, arguable point."

Generally, the ABCA considers the following factors:

(a) whether the point on appeal is of significance to the practice;

(b) whether the point raised is of significance to the action itself;

(c) whether the point on appeal is *prima facie* meritorious;

(d) whether the appeal will unduly hinder the progress of the action, and

(e) the standard of appellate review that would be applied if permission to appeal were granted.

If the issue on appeal goes to the core of the AUC's mandate and expertise, the ABCA will apply a highly deferential standard in reviewing the decision.

Standard of Review

Only questions of law or jurisdiction are appealable under the *Alberta Utilities Commission Act;* no appeal lies from decisions of mixed fact and law. The ABCA explained that section 29 of the *HEEA* confers jurisdiction on the AUC to alter service area boundaries when, in the AUC's opinion, it is in the public interest to do so. Such discretionary decisions within the AUC's mandate are accorded a high degree of deference.

As the ABCA noted in *FortisAlberta Inc v Alberta (Utilities Commission), 2015 ABCA 295*, the Supreme Court of Canada has "emphasized the need for deference where a tribunal is interpreting its own statute or statutes closely connected to its function, 'with which it will have particular familiarity.'" Accordingly, a presumption of deference, rooted in the institutional expertise of tribunals, applies to the AUC's interpretation of such statutes.

The ABCA found that the issues raised in the permission to appeal application primarily challenged the discretionary decisions of the AUC in an area squarely within its mandate. Deference is warranted when a tribunal interprets statutes "closely connected to its function." Accordingly, the ABCA concluded that the AUC's interpretation of the relevant statutory provisions would be accorded deference on appeal and reviewed on a reasonableness standard.

Proposed Grounds for Appeal

Failure to Consider and Interpret Relevant Sections of the Municipal Government Act

This proposed ground of appeal was based on the AUC concluding that FortisAlberta's application was in the public interest. The AUC identified four "public interest" grounds, three of which were connected to or directly related to the purposes and powers afforded to municipalities under the *Municipal Government Act*.

The ABCA found that, in essence, this proposed ground of appeal was a challenge to the sufficiency of the AUC's reasons.

The ABCA noted that the main task of the AUC was to determine whether the alignment of the franchise areas with the overlapping REA areas was in the public interest. It considered the competing arguments and determined that it was in the public interest to grant FortisAlberta's application. The AUC further minimized the effect of its decision by grandfathering existing relationships between REAs and their customers. The ABCA found that these decisions were directly within the ambit of the AUC's expertise. The ABCA held that, given the standard of appellate review, the alleged error of the AUC in failing to specifically discuss certain provisions of the *Municipal Government Act* and its regulations did not merit an appeal to the ABCA.

Failure to Give Effect to the Principle of Statutory Coherence

EQUS argued that the AUC failed to reconcile the provisions of legislation that conflicted with the authority of municipalities to grant franchises under the *Municipal Government Act*, specifically:

(a) the right of REA members to self-supply under the *Rural Utilities Act*;

(b) the right and authority of REAs to perform retail functions on behalf of members under the *Roles, Relationship and Responsibilities Regulation*, and

(c) the formation of REAs pursuant to the *Rural Utilities Act*.

The ABCA found that there was no merit to this ground of appeal, given the appellate deference owed to the AUC in determining the public interest. The ABCA found that the AUC's decision was reasonable, based on the following:

(a) the AUC noted that it must ascertain the public interest first by reference to the legislative scheme and most particularly what the legislature intended;

(b) the AUC found that it was required to assess applicable utility provisions in the *Municipal Government Act*, the purpose of REAs, the AUC's oversight of municipal grants of franchise under the *Electric Utilities Act* and its authority over service area designations in the *HEEA*; and

(c) the AUC considered how these statutes work together and determined the public interest on this basis.

<u>Error of Jurisdiction</u>

The ABCA did not find any arguable merit to the submission that the AUC exceeded its jurisdiction.

The ABCA affirmed that true questions of jurisdiction are exceptional. Where a tribunal is interpreting its home or related statutes, questions of true jurisdiction are to be read narrowly. The ABCA noted that the *HEEA* expressly conferred jurisdiction on the AUC to alter service area boundaries when it is in the public interest to do so. The ABCA found that this was precisely what the AUC did.

<u>Summary</u>

The ABCA did not find that there were errors of law or jurisdiction which would merit an appeal. The ABCA therefore dismissed EQUS' application for permission to appeal the AUC Decision.

ALBERTA ENERGY REGULATOR

Report of the Joint Review Panel - Teck Resources Limited Frontier Oil Sands Mine Project (2019 ABAER 008)

Application for Oil Sands Mine Project

On May 24, 2016, the federal Minister of Environment and Climate Change (the "Minister") and the CEO of the AER announced the establishment of a joint review panel (the "Panel") to consider Teck Resources Limited ("Teck")'s application to construct, operate, and reclaim an oil sands mine and processing plant (the "Frontier Project" or "Project"). The Panel concluded that the Frontier Project was in the public interest, and recommended the Minister approve the Project, subject to conditions.

Project Description

The Frontier Project would be situated 110 kilometres north of Fort McMurray, Alberta. The Project disturbance area would be 29,217 hectares, and the Project would operate for 41 years. The Frontier Project would produce about 41,300 cubic metres per day (260,000 barrels per day) of bitumen.

Creation of Joint Review Panel

The *Oil Sands Conservation Act* ("*OSCA*") required the Panel to consider whether the proposed Project is in the public interest. Section 15 of Responsible Energy Development Act ("*REDA*") and section 3 of REDA General Regulation also required the Panel's consideration of the social and economic effects of the Frontier Project and of the effects of the Frontier Project on the environment.

As part of its review, the Panel was to gather information, conduct an assessment of the effects of the Frontier Project, including upon Aboriginal and Treaty rights, and prepare a report containing recommendations to the federal Minister of Environment. Final decision-making authority regarding whether to approve the Project would rest with the Minister of Environment, Canada or the Governor in Council.

Decision

Public Interest

The Panel concluded that the Frontier Project was in the public interest. The Panel noted that the Frontier Project would be located in an area Alberta has identified as being important for bitumen extraction. The Project would provide significant economic benefits, including the expected creation of 7,000 jobs during construction and up to 2,500 operation jobs during the 41-year life of the mine. The Panel found that the Project was anticipated to contribute more than $70 billion directly to federal, provincial, and municipal governments.

Social and Economic Effects and Effects on the Environment

Although the Panel found that overall approval of the Frontier Project was in the public interest, the Panel found that there would be significant adverse Project and cumulative effects on certain environmental components and Indigenous communities under the AER's authority. However, the Panel considered the effects to be justified, based on the following:

(a) In response to requests from affected parties, the Panel included recommendations to the governments of Alberta and Canada regarding management frameworks and plans in Appendix 6 of the Panel's report.

(b) The Panel also found that the *Lower Athabasca Regional Plan* was an appropriate mechanism for identifying and managing regional cumulative effects.

The Panel acknowledged that the level of detail available for some aspects of the Project design was limited and that, consequently, there would be some uncertainty regarding future conditions and the effectiveness of proposed mitigation measures. However, the Panel noted Teck's commitment to using an adaptive management approach and working with regulators, Indigenous communities, and other stakeholders to address uncertainties and issues that arise during construction and operation of the Project.

Summary

The Panel recommended approval of the Project subject to various approval conditions, set out in Appendix 5 of the Panel's report.

Request for Regulatory Appeal by ISH Energy Ltd. of Approval Issued to Canadian Natural Resources Ltd. (AER Request for Regulatory Appeal No.: 1910998)

Request for Regulatory Appeal - Gas Over Bitumen - Request Denied

In this decision, the AER considered ISH Energy Ltd. ("ISH")'s request for a regulatory appeal of the AER's decision to issue Approval 11475X to Canadian Natural Resources Limited ("CNRL").

The AER denied ISH's request for regulatory appeal.

Background

ISH has interests in gas resources located in the Gas Over Bitumen ("GOB") zone above CNRL's bitumen operations subject to Approval 11475. ISH's gas well interests have been shut-in since 2005 by order of the Alberta Energy and Utility Board ("EUB") (the AER's predecessor).

Legislative Scheme

The applicable provision of *REDA*, section 38, states:

> 38(1) An eligible person may request a regulatory appeal of an appealable decision by filing a request for regulatory appeal with the Regulator in accordance with the rules. [Underlining added.]

Section 38(1) of *REDA* sets out a three-part test for standing for a regulatory appeal. The components of the test are:

(a) The requester must be an "eligible person";

(b) The decision from which an appeal is sought must be an "appealable decision"; and

(c) The request must have been made in accordance with the requirements of the *Alberta Energy Regulator Rules of Practice* (the "*Rules*").

Further, where a requester meets the tests set out in section 38(1) of *REDA*, the AER has the discretion pursuant to section 39(4) of *REDA* to dismiss a request for regulatory appeal if the AER considers that for any reason the request is not be properly before it, including where it concludes the request is without merit.

Request for Regulatory Appeal

In its request for a regulatory appeal, ISH submitted that it was an "eligible person" to request a regulatory appeal because:

(a) ISH would be directly and adversely affected if CNRL was to conduct operations under Approval No. 11475X, without the drilling of observation wells;

(b) the EUB had found that the barrier between the Wabiskaw gas resource and the Wabiskaw-McMurray bitumen formation was insufficient, and therefore ISH's interests in gas in the GOB zone were at risk; and

(c) ISH's gas located in the GOB zone overlying CNRL's operations was even more at risk in the absence of observation well monitoring taking place during bitumen production operations.

AER Reasons for Decision

The AER denied ISH's request for regulatory appeal, finding that there was no 'appealable decision' and that ISH was not an 'eligible person' as it was not directly and adversely affected by the AER's decision to approve the application. The AER's findings in support of this determination included the following:

- The adverse impact that ISH alleged (that its rights to the overlying GOB may be impacted by steam chamber growth into the GOB), did not arise from the removal or absence of CNRL's proposed observation wells, but related primarily to CNRL's previously approved operations.

- ISH should have properly raised these concerns in 2007 in response to CNRL's Application No. 1527354 to obtain approval for the Kirby Project, or in 2011 in response to CNRL's Application No. 1712215 to amalgamate existing approvals for Kirby North and Kirby South.

- There was no assurance that the presence of the observation wells would have prevented against or mitigated the potential for adverse effects to the GOB.

The drilling of observation wells was the result of a previous commitment by CNRL and was not a condition of Approval 11475, or any approval. Therefore, in the AER's view, its decision to approve the application removing the requirement for observation wells was not an appealable decision.

Request for Regulatory Appeal by Suncor Energy Inc. Pure Environmental Waste Ltd. (AER Request for Regulatory Appeal No.: 1919369)

Request for Regulatory Appeal - Request Granted

In this decision, the AER considered Suncor Energy Inc. ("Suncor")'s request, pursuant to section 38 of the *Responsible Energy Development Act* ("*REDA*"), for a regulatory appeal of the AER's decision (the "Decision") to issue to Pure Environmental Waste Ltd. ("Pure") AER Approval No. WM 211 (the "AER Approval Decision"). In the AER Approval Decision, the AER granted Pure's application for its proposed Hangingstone oilfield waste management facility (the "Waste Management Facility").

In this decision, the AER granted Suncor's request for a regulatory appeal, finding that Suncor was eligible to request a regulatory appeal and that Suncor's request was properly before the AER.

Legislative Scheme

The applicable provision of *REDA*, section 38, states:

> 38(1) An eligible person may request a regulatory appeal of an appealable decision by filing a request for regulatory appeal with the Regulator in accordance with the rules. [Underlining added.]

Section 38(1) of *REDA* sets out a three-part test for standing for a regulatory appeal. The components of the test are:

(a) The requester must be an "eligible person";

(b) The decision from which an appeal is sought must be an "appealable decision"; and

(c) The request must have been made in accordance with the requirements of the *Alberta Energy Regulator Rules of Practice* (the "*Rules*").

Further, where a requester meets the tests set out in section 38(1) of *REDA*, the AER has the discretion pursuant to section 39(4) of *REDA* to dismiss a request for regulatory appeal if the AER considers that for any reason the request is not be properly before it, including where it concludes the request is without merit.

Application of the Test

In this matter there was no dispute that the AER Approval Decision was an appealable decision. It was made pursuant to the *Oil and Gas Conservation Act* ("*OGCA*"), an energy enactment, without a hearing and therefore was an appealable decision as defined under section 36(a)(iv) of *REDA*.

The issue was whether Suncor met the definition of an "eligible person." As the decision appealed from was made under an energy enactment, eligible person in this instance was defined, as per section 36(b)(ii) of *REDA*, to be:

> A person who is directly and adversely affected by a decision [made under an energy resource enactment]…

Eligible Person

The AER Approval Decision granted Pure the approvals necessary to construct and operate the Waste Management Facility. The Waste Management Facility would be a new stand-alone cavern oilfield waste processing and disposal facility. Waste products received at the Waste Management Facility would be pumped into two underground salt caverns and displaced brine from the caverns would be re-injected into disposal wells.

The basis for Suncor's claim that it was directly and adversely affected by the AER Approval Decision was that, as the oil sands lease holder in the area, Suncor's ability to recover bitumen would be directly impacted by the AER Approval Decision.

The AER Approval Decision allowed Pure to construct the Waste Management Facility on a 10.46 acre surface disposition directly above oil sand rights held by Suncor. Suncor's planned operations in the area involved the development of Suncor's in situ operations, which were part of Suncor's Meadow Creek project involving steam assisted gravity drainage ("SAGD") operations.

The AER found that Suncor met the onus that it may be adversely and directly affected by the AER Approval Decision. The AER noted that SAGD development involved horizontal wells, the impact of which extended beyond the wells. The AER found that steam from the wells' steam chambers exited and expanded into the geological formation being accessed. The steam allowed the bitumen with the force of gravity to then flow into the lower production wells draining the bitumen.

<u>Without Merit</u>

Section 38(4) of *REDA* states in part:

> The Regulator may dismiss all or part of a request for regulatory appeal
>
> > (a) if the Regulator considers the request to be frivolous, vexatious or without merit,

The AER rejected Pure's submission that Suncor's request for regulatory appeal should be dismissed because it lacked merit. Rather, the AER found that, in addition to other matters, the issues related to resource sterilization and conservation made the appeal meritorious.

Accordingly, the AER granted Suncor's request for a regulatory appeal.

Syncrude Canada Ltd. Mildred Lake Extension Project and Mildred Lake Tailings Management Plan (AER Decision 2019 ABAER 006)

Tailings Management Plan - Application Approved

In this decision, the AER considered Syncrude Canada Ltd. ("Syncrude")'s application under section 13 of the *Oil Sands Conservation Act* ("*OSCA*") for amendments to existing Approval No. 8573 to construct, operate and reclaim the Mildred Lake Extension project ("MLX Project").

The AER found that the approval of the MLX Project was in the public interest and therefore approved the application subject to conditions.

<u>Background</u>

The MLX Project was a proposed open-pit mining project consisting of two open-pit mining areas in and beside its existing Mildred Lake operations. The east mine extension ("MLX east") would be west of the Athabasca River, and the west mine extension ("MLX west") would be west of the MacKay River. Development at the MLX west area required construction of a bridge across the MacKay River for development and operations.

The MLX Project was designed to sustain bitumen production levels after the current Mildred Lake North Mine pit is depleted. The mineable resource is estimated at 738 million barrels of recoverable bitumen. The MLX Project would use conventional shovel and truck mining technology and would extend the duration of mining activity by about 14 years.

Development of the MLX Project area would begin toward the end of 2019. Oil sands mining would begin at MLX west in 2024, followed by MLX east in 2028.

The MLX Project would use the existing Mildred Lake upgrader, extraction facilities, mining equipment, processing plants, and tailings facilities to process the mined ore.

<u>Mildred Lake Tailings Management Plan</u>

The AER found that several items in the Mildred Lake tailings management plan did not meet the intent of the *Tailings Management Framework* ("*TMF*") or *Directive 085: Fluid Tailings Management for Oil Sands Mining Projects (Directive 085)*. To address these deficiencies, the AER required Syncrude to submit an updated tailing management plan on or before January 31, 2023. The updated tailings management plan must be aligned with the intent of the *TMF* and *Directive 085*.

The AER directed that the updated tailings management plan must ensure that fluid treatment capacity is equal to or greater than the production rate of fluid tailings. Treatment capacity equal to production capacity must be achieved by December 31, 2025, ten years after the Tailing Management Framework was issued.

<u>Geotechnical and Dam Safety</u>

Syncrude proposed placing the produced tailings in currently approved facilities at the Mildred Lake site. Syncrude would use the existing external tailings pond at the Mildred Lake site and proposed placing centrifuge cake deposits and creating end-pit lakes in the in-pit areas of the MLX Project area.

The AER found that Syncrude's design approach was appropriate for the application stage. The preliminary mine design supported the mine plan by defining the limits of the mine pits, the locations of disposal areas, and the capacities of the disposal areas. The preliminary design also identified interactions and provided setback assessments for mine pits, disposal areas, plant sites, other mine infrastructure, and the environment.

The AER found that Syncrude's plan to use existing external tailings facilities for the MLX Project did not include changing the facilities other than extending their time of active operation.

The AER found that Syncrude's plan to construct an in-pit berm to buttress the final pit wall was acceptable. The berm would provide an in-pit storage space for overburden material with a short haul distance and provided a surface for the relocation of Highway 63.

The AER directed Syncrude to submit detailed geotechnical designs of final pit walls, external and in-pit overburden disposal areas, and reclamation material stockpiles six months before construction.

The AER further directed that Syncrude shall not begin any activities associated with dam or canal construction, major repair, decommissioning, closure, long-term cessation, or limited operation unless written authorization or approval amendment to the plan was granted by the AER.

<u>MLX West SAGD Setback Assessment</u>

The AER noted that Syncrude did not provide any monitoring data for pore pressure measurement or geomechanical modelling assessments to justify the adequacy of the buffer zone between Suncor's SAGD operation and Syncrude's MLX West Mine area. Syncrude did not provide an assessment of any impact of mine pit opening and overburden construction on the SAGD operation.

The AER found that if an excess pore pressure was present as a result of SAGD operation in the buffer zone, the construction of the overburden disposal area and reclamation material stockpile at MLX west would add to the pore pressure in the buffer zone. The AER found that for this reason, a geological-geomechanical characterization of the buffer zone supported by monitoring data and numerical modelling was necessary.

The AER directed Syncrude to provide a SAGD-mining impact assessment for the MLX west pit. The assessment needed to be supported by actual performance or monitoring data from an existing SAGD operation and by an additional monitoring program in the buffer zone before mine operation start-up. Depending on the results of the assessments, more monitoring might be required during mine operation as the mine pit is developed and overburden storage areas are being built.

<u>Air Quality</u>

As part of its Environmental Impact Assessment, Syncrude was required to assess the impact of air emissions, including the components of the project that would contribute emissions and potentially affect air quality.

The AER noted that the mine fleet was a major source of air emissions as a result of combustion of diesel fuel. As the North Mine pit was depleted, Syncrude would transition the mine fleet to the MLX west mine pit starting in 2023 and to MLX east in 2027.

It was the AER's opinion that the project would extend NO_x, SO_2, and $PM_{2.5}$ emissions for an additional 14 years. These were emissions that would not exist in the absence of MLX Project. The effects of NO_x and SO_2, in particular, would be cumulative and would contribute to 14 years of additional input to nitrogen and acid deposition in the local and regional ecosystem. The AER found that NO_x emission levels in particular needed to be managed to ensure meeting the Canadian Ambient Air Quality Standards and compliance of with Alberta air quality objectives and critical and target loads.

The AER required Syncrude to achieve the outcome of 12.7 tonnes per day of total mine fleet NO_x emissions, as applied for, and included a NO_x emission limit as a condition of approval, to be met by 2030, the operating year on which Syncrude based its air assessment scenarios.

The AER also required Syncrude to participate in and implement any management actions required by Alberta with respect to triggers and thresholds for acid deposition established under the *Alberta Land Use Framework, Lower Athabasca Regional Plan* ("*LARP*"), Air Quality Management Framework. The AER indicated that Syncrude may also be required to develop and implement actions to achieve forthcoming standards established under the Canadian Ambient Air Quality Standards.

The AER found that proactive management of dust emissions at MLX was required to mitigate health and safety risks. The Panel required Syncrude to develop and implement a dust management and mitigation plan.

Greenhouse Gas Emissions

A greenhouse gas management plan was a requirement of Draft *Directive 023: Oil Sands Project Applications* and was part of Syncrude's *OSCA* application.

Despite some uncertainty, the AER found that the MLX Project would result in a relatively small contribution to cumulative greenhouse gas emissions from the Alberta oil sands. The AER found that, considering that Syncrude North Mine pit greenhouse gas emissions would be discontinued, the MLX Project greenhouse gas emissions would likely be a relatively small increase to Alberta greenhouse gas emissions. The AER found that Alberta's *Carbon Competitiveness Incentive Regulation* ("*CCIR*") and *Oil Sands Emissions Limit Act* were the appropriate tools to manage and mitigate the MLX Project greenhouse gas emissions.

MLX West End-Pit Lake

Suncor proposed that, at the end of mining life, an end-pit lake would be formed within MLX west ("MLX west end-pit lake"). Tailings would not be placed into the MLX west end-pit lake, but seepage from centrifuge cake placement would no longer be diverted to the closed-circuit recycle water system at closure and would instead be expected to seep into MLX west end-pit lake.

The AER found Syncrude's water quality model developed for the MLX west end-pit lake was simplistic and relied on a number of unconfirmed assumptions given the lack of site-specific data. Therefore, the AER required Syncrude to regularly update its water quality models for the MLX Project, including for MLX west end-pit lake water quality as site-specific data becomes available and as more complex processes are better understood and accounted for in the models.

Effects in Fisheries and Fish Habitat

The AER found that impacts on fish and fish habitat associated with the MacKay River watershed could be appropriately mitigated by the Owl River offset, the proposal to use the drainage channel, and by the AER's recommendation that Syncrude work with the Department of Fisheries and Oceans ("DFO") and Athabasca Chipewyan to create an additional offset enhancement in the MacKay River watershed.

Reclamation

On the issue of reclamation as mitigation for impacts of the MLX Project, the AER found there were uncertainties about whether the reclaimed landscape could achieve an equivalent level of biodiversity, what species it would support after reclamation, and the time frame over which this could be accomplished. The AER found that the timeline for reclamation, knowledge gaps around the effectiveness of reclamation to support diverse wildlife habitat, and lack of information about the final reclamation and closure plan, combined to present serious challenges to Syncrude's goal of using reclamation as mitigation for land and wildlife disturbance.

There was uncertainty about whether Syncrude's reclamation and closure activities would create a viable ecosystem capable of sustaining wildlife. There was a high degree of uncertainty about the potential for the closure landscape to support caribou, given the nature of the habitat they require. There was potential for the closure landscape to support moose habitat, but to what extent was unknown.

The AER found that the biggest and most significant impact on wildlife and wildlife habitat was the temporal nature of the project; the MLX site would not be certified as reclaimed until 2130. This represented a 100-year period where the land was not available for wildlife use or wildlife habitat. Based on the evidence presented, it was clear to the AER that impacts would happen quickly whereas reclamation would occur very slowly.

Noise

The AER accepted that the noise effects of the MLX Project in the region were expected to be moderate to low.

The AER found that the noise impact assessment provided by Syncrude was acceptable and that the MLX Project was expected to meet the requirement of *Directive 038: Noise Control* ("*Directive 038*"). The modelling results indicated that the cumulative sound levels would be higher than the permissible sound levels at receptor 4 at year 2029 and receptor

5 at years 2023 and 2029. Potential exceedances at receptor 5 were due to the noise exceedances attributed to the Suncor Base Mine operations, which was not related to activities at the MLX Project.

The AER required Syncrude to conduct an acoustical survey for the MLX east mine operations. If the acoustical study report shows noise levels that do not meet *Directive 038* criteria, Syncrude would be required implement a noise mitigation plan and conduct a follow-up acoustical survey within six months.

Reclamation and Closure Plan

The AER found Syncrude's reclamation and closure plan met the requirements and reclamation outcomes outlined in Alberta's approved *LARP.*

The AER noted that there would also be some level of uncertainty with a long-term reclamation planning that would span over multiple decades. These uncertainties included the type of habitat that would form at closure. Despite these uncertainties, the AER determined that Syncrude's proposed reclamation methods were consistent with existing policy direction and met reclamation standards and guidelines.

The AER found Syncrude's commitment to the reclamation engagement focus group and ongoing collaboration with Indigenous groups related to reclamation and closure planning to be an acceptable approach.

Terrain and Soils

The AER noted that the MLX Project construction would alter topography, site elevation, and drainage patterns within the MLX Project footprint. Syncrude said most of the soil from the development area would be salvaged and stockpiled for use during reclamation.

The AER found that the reclamation material balances for MLX west and MLX east showed that enough material was available to meet placement requirements.

As a condition of approval, the AER required Syncrude to cap coke and centrifuge cake before placing cover soil and subsoil. This condition was to protect the rooting zone and did not consider other objectives of placing capping material on tailings deposits, such as geotechnical stability and settlement, management and control of water treated tailings, and drainage.

Socioeconomic Effects

Overall, the AER found that the project would have a positive economic effect on the regional, provincial, and Canadian economy with respect to gross domestic product, labour income, employment, taxes, and royalties. The effect would be moderate in magnitude and long-term in duration and would contribute to the overall economic sustainability of the region and province.

The AER found that the approach used by Syncrude to estimate the carbon cost for the MLX Project was sound and consistent with current regulatory requirements for carbon pricing. The $864 million cost estimate was based on Alberta's *Carbon Competitiveness Incentive Regulation*, which currently uses a price of $30 per tonne, increasing to $50 per tonne by 2024. Syncrude used a number of conservative assumptions in developing its carbon-price estimate, including forecasting its emissions based on peak levels of existing mining and upgrading operations, which would be replaced by the MLX Project as current production diminished at the North Mine, and by assuming that there would be no technological improvements or lower emission intensities over the life of the project.

Treaty Rights, Traditional Land Use Activities, and Culture

The AER found that the MLX Project would impact the ability of Athabasca Chipewyan land users to continue to hunt in the area of MLX west and along the MacKay River corridor adjacent to MLX west.

The AER recognized that the Athabasca River corridor held traditional and cultural significance for Athabasca Chipewyan; however, the evidence that the corridor in proximity to MLX east was used for hunting was weak. The AER noted that one elder said he avoided the area because he perceives it is already contaminated. The AER also noted that Athabasca Chipewyan's experts said that moose tend to avoid areas within 300 m of mines, and that traditional users prefer to hunt away from industrial activity.

The AER acknowledged that hunting occurs in the MLX west area and that Athabasca Chipewyan members hunt moose and beaver from the MacKay

River and along the corridor. The AER found that moose would be displaced at MLX west, thus impacting their distribution and accessibility to Athabasca Chipewyan. The AER acknowledged that loss of habitat and displacement would cause some interruption to Athabasca Chipewyan's traditional hunting activity in the area.

Decision - MLX Project Approval

The AER explained that, to determine whether the MLX Project was in the public interest, as required under *OSCA*, it considered all the submissions, evidence, and relevant legislation, Syncrude's proposed mitigations and commitments, as well as the conditions imposed by AER. The AER weighed impacts on Athabasca Chipewyan's treaty rights and traditional use activities, the social and economic impacts of the MLX Project, and the impacts on the environment.

The AER found that approval of the MLX Project was in the public interest based on the following:

(a) the economic and employment benefits of the project in terms of their contribution to the regional and provincial economy and to the local and provincial tax base were considerable;

(b) the adverse impacts on Athabasca Chipewyan, in particular on their ability to continue to conduct traditional activities could be adequately mitigated through standard approval conditions and conditions imposed by the AER; and

(c) the potential impacts on Athabasca Chipewyan were not enough to outweigh the economic benefits from the MLX Project.

The AER further found that:

(a) the MLX Project was consistent with the LARP objective of optimizing Alberta's oil sands resources and ensuring First Nations' ability to continue to carry out traditional activities within reasonable proximity to population centres;

(b) where the MLX Project contributed to regional cumulative impacts, the conditions imposed by the AER were sufficient to mitigate these impacts; and

(c) Syncrude's *OSCA* application was consistent with the purposes of the *OSCA* including but not limited to ensuring the orderly, efficient, and economic development in the public interest of the oil sands resources of Alberta.

As a result, the AER approved *OSCA* Application No. 1820856 for the MLX Project, subject to the conditions.

AER Bulletin 2019-16: National Energy Board Safety Advisory

Monogram Electric Resistance Weld - Potential Hazard

On July 3, 2019, the NEB issued safety advisory NEB SA 2019-01 to inform pipeline operators of a potential hazard regarding API 5L Monogram Electric Resistance Weld pipe joints manufactured by Hyundai Steel in their Ulsan, South Korea, mill.

A review of recent pipeline incidents in Alberta did not find any links to the hazard identified in NEB SA 2019-01. However, this hazard, if present, could lead to pipeline integrity issues in the future. As such, the AER reminded licensees that they must conduct an engineering assessment if they become aware of a condition that can lead to failures in their pipeline systems.

AER Bulletin 2019-17: 2019/20 AER Administration Fees (Industry Levy)

Administration Fees

The AER noted that its 2019/20 budget was not yet approved. As a result, the AER stated that it would issue two sets of administrative fees for 2019/20. The first set of administrative fees would allow the AER to operate until an approved budget was provided by the Government of Alberta, at which point the AER would issue a second set of administrative fees to collect the remaining approved amount.

2019 Administration Fees (Industry Levy)

The amount of each invoice would depend on the AER's revenue requirement, 2018 production volumes, the number of wells and schemes, and the number of operators within the sector. Invoices to operators detailing the fee calculations were to be mailed on July 12, 2019, and payments due by August 12, 2019.

The *Responsible Energy Development Act* ("*REDA"*), authorizes the AER to make rules to levy an administration fee on the oil and gas, oil sands, and coal sectors, and impose a late-payment penalty, set at 20 percent on any portion of the fee remaining unpaid after the due date. Invoices for administration fees are sent to and made payable by the party that was the operator on record (as defined in section 29 of *REDA*).

For conventional wells and oil sands schemes, "operator" means the entity that filed well production, injection, or disposal data, or all three, with Petrinex, Canada's Petroleum Information Network. If the operator failed to pay the fee, the late-payment penalty would be added and the AER would pursue the approval holder (if the actual operator and approval holder were two different parties) for payment of the full amount.

If the administration fees or penalty was not paid, the AER could use various enforcement tools to collect payment, including

(a) closing producing wells or facilities.

(b) garnishing production from operating wells and facilities to collect any outstanding debts;

(c) enforcing against the AER's priority lien under section 103 of the *Oil and Gas Conservation Act* on a defaulting approval holder's wells, facilities, and pipelines and on land or interests in land, including mines and minerals, equipment, and petroleum substances; and

(d) using other enforcement tools, as set out in the legislation.

<u>Oil and Gas</u>

The AER explained that the administration fee in the conventional oil and gas sector was based on individual well production of oil/bitumen or gas and the number of production and service wells for the year ended December 31, 2018.

All operating wells were classified into one of eight base fee classes, as set out in the *Alberta Energy Regulator Administration Fees Rules* ("*AFR*"). In addition, an adjustment factor would be applied to each base fee. This adjustment factor would ensure that the total administration fee collected for the sector satisfies the revenue requirement for the AER.

<u>Alberta Upstream Petroleum Research Fund</u>

The Canadian Association of Petroleum Producers ("CAPP") and the Explorers and Producers Association of Canada ("EPAC") jointly requested that the AER's administration fee process be used to collect $4,194,000 to fund the Alberta Upstream Petroleum Research Fund ("AUPRF") in 2019. The AER agreed to assist and included an amount for this funding in the oil and gas well administration fee invoices. Payment of the AUPRF was voluntary.

<u>Oil Sands</u>

Fees were to be levied based on operating information for the 2018 calendar year into the following categories:

(a) primary ongoing;

(b) thermal ongoing;

(c) thermal growth;

(d) mining ongoing; and

(e) mining growth.

An operator could have activities in more than one category. Each Category would be subject to an adjustment factor.

<u>Coal</u>

The administration fee for coal was based on each mine's share of total production volumes for the year ending December 31, 2018. It was set at $0.118462 per tonne of coal as specified in the *AFR*.

AER Bulletin 2019-18: New Working Interest Cost Claim Form

Cost Claims - Working Interest Participants

The AER released a new form for submitting cost claims for defaulting working interest participants.

Once abandonment or reclamation activities are completed, an active company may submit a claim to the AER for costs incurred on behalf of another working interest participant. The AER would then determine if the claim was eligible under section

70(2)(b) of the *Oil and Gas Conservation Act* and, if so, sends the claim to the Orphan Well Association.

The entire process for working interest claims has been set out by the Orphan Well Association on their website. At the date of publication, the updated form was available on the AER's website.

ALBERTA UTILITIES COMMISSION

ATCO Electric Ltd. 2018-2019 Transmission General Tariff Application (AUC Decision 22742-D01-2019)

Electricity - General Tariff

In this decision, the AUC considered ATCO Electric Ltd. ("AET")'s 2018-2019 transmission general tariff application for the test years 2018 and 2019 (the "Application").

As part of the Application and associated updates, AET sought AUC approval for revenue requirements of $691.7 million in 2018 and $699.5 million in 2019. AET also sought approval of rates based on AET's approved forecast revenue requirements.

The AUC found that not all of the forecast revenue requirements requested in the Application were reasonable. The AUC ordered that AET file a compliance filing to the Application to reflect the AUC's findings, conclusions, and directions in this decision.

<u>Forecasts Not Accepted</u>

The AUC did not accept the following AET forecasts:

(a) the level of full-time equivalents ("FTEs");

(b) 2019 escalation (inflation) rates;

(c) 2018 severance costs;

(d) costs and allocations with respect to ATCO Park;

(e) cost allocations concerning Alberta PowerLine Limited Partnership ("Alberta PowerLine");

(f) costs with respect to the Variable Pay Program ("VPP");

(g) certain operating and maintenance ("O&M") costs; and

(h) the AUC did not approve AET's request to treat TCM project number 50463 for line 9L101 ("Kearl Lake") as a system cost.

FTEs

The AUC found that AET failed to justify its requested FTEs and associated dollar amounts in the test years. Consequently, the AUC directed AET to use its 2018 actual FTEs as the approved FTE complement for 2018. The 2018 FTEs were approved as the opening 2019 FTE complement.

2019 Escalation (Inflation) Rates

The AUC was not persuaded that the current Alberta economic climate supported an out-of-scope labour escalation rate of 3.0 percent in 2019. Rather, the AUC found that an out-of-scope labour escalation rate of 2.0 percent for 2019 better reflected current labour inflation rates, similar to what the AUC approved for AET's in scope inflation rate.

2018 Severance Costs

AET allocated the severance payment amounts in its revenue requirement forecasts based on where the severed position was providing its services in 2018. The AUC did not find this to be a reasonable allocation of severance payments. The AUC directed AET to provide in its compliance filing a recalculation of its 2018 severance costs based on the proportion of years of service each severed position provided to AET's transmission function. The AUC approved AET's 2019 severance costs of $1.5 million on a placeholder basis and committed to review the historical service years within ATCO companies to determine the final approved amounts in AET's next general tariff application.

Costs and Allocations With Respect to ATCO Park

AET forecast increased head office rent in each of the test years due to a move to a new corporate head office, ATCO Park, built by its parent company, ATCO Ltd. The AUC found AET had failed to meet its onus to demonstrate that the head office rent costs it was seeking to recover in rates during the 2018-2019 test period (and beyond) were just and reasonable. To determine AET's reasonable share of corporate rent costs, the AUC directed AET to provide additional evidence in its compliance filing.

Cost Allocations Concerning Alberta PowerLine

Alberta PowerLine Limited Partnership ("Alberta PowerLine") owned 100 per cent of the Fort

McMurray West 500-Kilovolt Transmission Line Project (the "APL Project"). AET provided management services, O&M services, route development and design build management services to Alberta PowerLine with respect to the APL Project under a service concession arrangement.

AET explained that head office costs were allocated to operating entities based on a formula that took into account equal weightings of total assets, net revenues and labour costs. AET confirmed that it would not be until the in-service date of the APL Project that Alberta PowerLine would become an operating entity within the pool and be allocated head office costs. Because of the head office costs allocation methodology, there would therefore be a two-year lag regarding the inputs to the costs in question.

The AUC took issue with the methodology for allocating head office costs, in particular the two-year lag, given that AET was already providing services to Alberta PowerLine. The AUC directed AET to propose, in its compliance filing, a proxy for labour, including its rationale and calculations, to be used in the head office cost allocation calculation to account for Alberta PowerLine.

VPP Costs and Reserve Account

The AUC approved as a placeholder AET's VPP forecasts at 80 percent of the eligible employee payout amounts, noting that this determination was consistent with the AUC's previous VPP approval in Decision 20272-D01-2016. The AUC found that it was unrealistic for the AET to assume that all of the employees eligible for VPP would meet 100 percent of the targets set for them, and that all FTEs eligible for VPP would be with AET when the VPP payouts were made. The AUC also noted that the actual VPP payouts were inconsistent with historical forecasts prepared by AET, making it difficult for the AUC to rely with any confidence on AET's VPP forecasts.

AET sought the continuation of its VPP reserve account. AET also requested that approved but unused VPP amounts be carried forward and added to next year's VPP reserve. AET proposed that VPP payments made in excess of the approved forecast for any given test year be recovered through the reserve in a future test year. The AUC denied AET's request to amend the mechanics of the reserve account, noting that granting AET's request would, in effect, allow the VPP reserve account to act as a deferral account. The AUC explained that in Decision 2013-358, it removed deferral account treatment for AET's VPP costs and that the concerns underlying that decision had not changed.

The AUC directed AET to reflect the AUC's findings and directions regarding VPP costs from this decision in AET's compliance filing. The AUC noted that in implementing this direction, AET was to take into account the mechanics of the reserve account, including how it could best operate the VPP reserve account to avoid an increasing accumulated balance

O&M Costs

AET was required by the *Surface Rights Act* to pay annual compensation to landowners for transmission structures located on their property. Among the costs included were annual structure payments and any costs relating to Surface Rights Board ("SRB") proceedings. AET requested $6.9 million and $7.3 million in costs for the respective 2018 and 2019 test years. However, AET confirmed in its rebuttal evidence that 2018 actual SRB costs were less than the applied-for amounts (based on forecasts) but that AET still expected the 2019 SRB costs to be consistent with its forecast.

The AUC accepted there was uncertainty regarding SRB costs consistent with AET's $200,000 reduction in its forecast costs for 2018. The AUC therefore directed AET to reflect, in its compliance filing, the $200,000 reduction for the 2018 test year. The AUC also directed AET to reduce the 2019 forecast by $200,000.

Regarding vegetation management, the AUC found that a reduction to AET's 2019 forecast was warranted because there was insufficient support that the forecast work required to be completed in 2019. The AUC therefore directed that AET reduce the forecast vegetation management costs for 2019 by 10 percent in its compliance filing.

Kearl Line System Costs

In the Application, AET filed a business case supporting the relocation of the Kearl line as requested by Fort Hills Energy to accommodate its oilsands expansion project. The AUC found that the costs of the relocation should be the responsibility of the owner of the Fort Hills mine. Therefore, the AUC denied the forecast capital expenditures in the amount of $1.0 million and $3.0 million in 2018 and 2019, respectively.

Continued Use of Deferral and Reserve Accounts

AET sought AUC approval for the continued use of certain previously approved deferral and reserve accounts.

The AUC directed that the following reserve accounts be maintained by AET: the reserve for injuries and damages (“RID”), VPP, and rate case costs.

The AUC denied AET’s request to expand the scope of its existing International Financial Reporting Standards (“IFRS”) deferral account to permit it to seek approval of new depreciation rates.

Discontinuance of Deferral and Reserve Accounts

AET sought AUC approval for the discontinuance of the following previously approved deferral and reserve accounts for the test period:

(a) right-of-way payments;

(b) income taxes relating to: capital repair costs and deductible capital costs;

(c) debenture rates; and

(d) vegetation management.

However, the AUC directed that AET maintain these accounts for the test period.

Additional Approvals

In its application, AET sought the continued collection of federal future income tax (“FIT”) for the test period. AET submitted that the continued collection of FIT would help maintain credit metrics at a level that would sustain an “A” rating and minimize the risk of a credit rating downgrade that would result in higher AET costs for new debt issues. The AUC approved AET continuing to collect FIT for the test years, as its sole credit relief measure.

The AUC also approved AET’s isolated generation operating costs and AET’s forecasted depreciation expenses as filed.

Order

The AUC ordered that AET file its 2018-2019 transmission general tariff application compliance filing by August 8, 2019, to reflect the findings, conclusions, and directions in this decision.

AUC Bulletin 2019-09: Interim Information Requirements for Solar and Wind Energy Power Plant Applications

Solar Energy - Wind Energy - Rule 007

In this bulletin, the AUC announced new interim information requirements for wind and solar energy projects. These new information requirements apply to all new wind and solar energy Rule 007*: Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments* (“Rule 007”) applications filed on or after October 1, 2019.

Solar Glare Assessment

Solar glint and glare refers to a direct reflection of the sun in the surface of the photovoltaic solar panel. Generally, glint is a momentary flash of bright light while glare is a continuous source of bright light. Shadow flicker refers to the flickering effect caused when rotating wind turbine blades periodically cast shadows over neighbouring properties as they turn, through constrained openings such as windows.

Applicants for new solar energy projects must include a solar glare assessment in their Rule 007 application. The solar glare assessment must describe the time, location, duration, and intensity of solar glare predicted to be caused by the project. It should also describe the potential impact on dwellings and transportation routes surrounding the proposed solar energy project, and any mitigation measures proposed. Applicants are required to identify the software or tools used in their assessment, the assumptions of input parameters utilized, and the qualification of the person performing the assessment.

Shadow Flicker Assessments

Applicants for new wind energy projects must include a shadow flicker assessment in their Rule 007 application. The shadow flicker assessment must describe the time, location and duration of the shadow flicker predicted to be caused by the project. It should also describe any potential impact upon residential and non-residential buildings surrounding the proposed wind energy project, and any mitigation measures proposed. Applicants are required to identify the software or tools used in its assessment, the assumptions of input parameters utilized, and the qualification of the person performing the assessment.

AUC Bulletin 2019-10: AUC Rule 007 - Initiation of a Review and Stakeholder Consultation Process

Rule 007 - Review - Consultation Process

In this bulletin, the AUC announced that it had initiated a review of AUC Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments* (“Rule 007”). The goal of the review was to update and streamline existing requirements to make the application process more efficient for applicants, intervenors, and the AUC.

As part of this review, the AUC sought stakeholder comments on the following issues:

(a) Indigenous consultation;

(b) end-of-life management for power plants;

(c) emergency response plan;

(d) time extension applications for power plants;

(e) notification and participant involvement program;

(f) solar glint and glare assessment;

(g) shadow flicker;

(h) review of buildable area concept for wind development; and

(i) battery storage.

The AUC indicated the Rule 007 review would proceed in two stages:

(a) Stage 1: The AUC will first review stakeholder feedback in response to this bulletin and draft potential rule changes on each of the specific issues identified. Following that review, the AUC will invite further stakeholder comments and suggestions on the proposed changes that are introduced.

(b) Stage 2: The AUC will incorporate the feedback received for each of the specific issues and incorporate all of the changes into a complete blackline revision to Rule 007, which will be circulated to stakeholders for final review and comment. It is anticipated that the second stage of the review will be initiated in early 2020.

Stakeholders can use the AUC Engage consultation tool, on the AUC website, to provide general comments on any of the listed topics.

AUC Bulletin 2019-11: Updated Micro-Generation Notice Submission Guideline Released, Forms Changed and Removed From Appendix in Rule 024: Rules Respecting Micro-Generation

Micro-generation - Rule 024

In this bulletin, the AUC announced an update to the AUC’s Micro-Generation Notice Submission Guideline. The revised guideline summarizes the current processes required to obtain approval for micro-generation connection to the grid. The guideline reflects the updated safety, electric and procedural information and was modernized with new graphics for illustration purposes.

As a result of the work completed on the guideline, the associated forms in Rule 024: *Rules Respecting Micro-Generation* were removed from the rule to specify form content without restricting the format.

AUC Bulletin 2019-12: Assessment of Specified Penalties for Self-Reported Contraventions

Contravention of AUC Rules - Specified Penalties

On January 1, 2019, Rule 032: Specified Penalties (“Rule 032”) came into effect. Rule 032 established specified penalties for contraventions of select provisions of AUC rules related to customer care and billing issues and, in June 2019, the AUC began issuing specified penalties pursuant to this rule.

The AUC considered feedback following the issuance of the June 2019 specified penalties and, on a go-forward basis, the AUC will consider multiple occurrences of a contravention specified in the AUC Rule 032 penalty table as one contravention, provided those contraventions:

(a) are self-reported;

(b) relate to the same customer name and site ID number;

(c) occurred in consecutive months or billing periods; and

(d) were carried out by the same distinct legal entity.

Effective July 19, 2019, the amended evaluation process, was intended to provide an increased incentive for utilities to self-report contraventions while also providing additional certainty regarding how specified penalties for self-reported contraventions will be assessed.

AUC Announcement: Regulatory Burden Stakeholder Consultation

Regulation - Stakeholder Consultation

AUC regulation, as with most forms of regulation, imposes costs on regulated companies. These include the costs of meeting regulatory process requirements and the administrative costs of running the agency, most of which are ultimately borne by consumers.

The Alberta government passed the *Red Tape Reduction Act* with the objective of reducing regulatory burden to enhance economic growth, innovation, competitiveness and investment in Alberta businesses.

The AUC indicated it is interested in consulting broadly with stakeholders to explore ways to further reduce regulatory burden. Key areas of focus for the consultation include AUC rules or procedural steps that may have become outdated or unnecessary, and opportunities to streamline and improve regulation and adjudication processes.

As part of its consultation, the AUC indicated it would host a roundtable on October 4, 2019 in its Calgary office to discuss comments received.

Canadian Utilities Limited Application for ATCO Power (2010) Ltd. to Dispose of all of its Shares in ATCO Power Canada Ltd. and to Transfer Ownership of the Oldman River Hydro Project, (AUC Decision 24629-D01-2019)

Transfer of Fossil Fuel-Based Power Generation Business

In this decision, the AUC considered whether to approve the following transactions:

- ATCO Power (2010) Ltd.'s disposition of all of its shares in ATCO Power Canada Ltd. to Heartland Generation Ltd. and for the transfer of the Cumulative Preferred Shares Series V in the capital of Alberta Power (2000) Ltd. from Canadian Utilities Limited ("CUL") to ATCO Power (2010) Ltd. and then from ATCO Power (2010) Ltd. to ATCO Power Canada Ltd (the "Heartland Transaction").

- ATCO Power Canada Ltd.'s transfer of ownership of the Oldman River Hydro Power Plant, the Oldman River 806S Substation and associated connection order to ATCO Power (2010) Ltd (the "Oldman River Ownership Transfer").

<u>Requirement to Obtain AUC Approval of Certain Transactions</u>

CUL, being a designated owner of a public utility under section 101 of the *Public Utilities Act* ("*PUA*") and a designated owner of a gas utility under section 27 of the *Gas Utilities Act* ("*GUA*"), must obtain approval or an exemption from approval from the AUC if it engages in certain transactions outside of the ordinary course of an owner's business. Failing to do so means that the transaction is void.

<u>Application Filed with AUC for Approval of Transactions</u>

On June 5, 2019, CUL filed the following applications with the AUC:

(i) Application requesting a declaration pursuant to section 101(4) of the *PUA* and section 26(4) of the *GUA* that the Heartland Transaction is exempt from the application of sections 101(2)(d)(i) and 102(1) of the *PUA* and sections 26(2)(d)(i) and 27(1) of the *GUA*. Or in the alternative, an Order by the Commission approving the Heartland Transaction under sections 101(2)(d)(i) and 102(1) of the *PUA* and sections 26(2)(d)(i) and 27(1) of the *GUA*.

(ii) Application requesting approval for ATCO Power Canada Ltd. to transfer ownership of the Oldman River Hydro Power Plant, the Oldman River 806S Substation and associated connection order (collectively the "Oldman River Hydro Project") to ATCO Power (2010) Ltd.

The Heartland Transaction

Request for Exemption or Approval Under PUA and GUA

The AUC found that an exemption under section 101(2)(d)(i) of the *PUA* and section 26(2)(d)(i) of the *GUA* should only be granted in circumstances where the transaction is straight forward, of relatively small value and upon review raises no issues that might harm customers. Accordingly, the AUC decided to consider the application regarding the Heartland Transaction as one for approval (and not for an exemption).

Commission Findings

The AUC set out that the central question in deciding whether to approve a transaction outside of the ordinary course of business under section 101(2)(d)(i) of the *PUA* or section 26(2)(d)(i) of the *GUA*, is whether customers are harmed by the transaction. The customers in this case were the consumers of electricity and natural gas utilities served by ATCO Electric Ltd. and ATCO Gas and Pipelines Ltd.

The AUC approved the Heartland Transaction under section 101(2)(d)(i) of the *PUA* and section 26(2)(d)(i) of the *GUA,* based on finding that there was no harm caused to the regulated customers of ATCO Electric Ltd. and ATCO Gas and Pipelines Ltd.

The AUC noted that the no-harm test and the factors considered by the AUC had evolved over the years and the test now reflected the following:

- customers, to the maximum extent possible, are to be protected against any negative ramifications arising from the transactions;
- customers are not entitled to a level of post-transaction regulatory certainty they would not have realized if the transaction had not been approved; and
- customers are at least no worse off after the transaction is completed after consideration of the potential positive and negative impacts of the proposed share transactions.

The AUC held that the Heartland Transaction related to non-utility, non-rate regulated assets and would not have a harmful effect on regulated utility service or the rates charged for those services. Nor would the Heartland Transaction negatively affect regulatory oversight of CUL. The AUC therefore found that the no-harm test was satisfied and approved Heartland Transaction.

The Oldman River Ownership Transfer

Application for Transfer of Ownership

CUL filed an application under sections 10, 15, 18, 19 and 23 of the *Hydro and Electric Energy Act* ("*HEEA*") to transfer ownership of the Oldman River Hydro Project from ATCO Power Canada Ltd. to ATCO Power (2010) Ltd.

Commission Findings

The AUC held that, based on the information provided, ATCO Power (2010) Ltd., through CUL, had demonstrated that it was eligible to hold the power plant approval, substation licence and connection order in its name.

The AUC noted that in an information response, CUL confirmed that ATCO Power Canada Ltd. was currently bound by a use of works agreement regarding the Oldman River Hydro Project, including conditions that the removal of the power plant would be at the sole expense of ATCO Power Canada Ltd., and done in a manner acceptable to the Minister of the Environment.

The AUC did, however, note that while the applicant requested AUC authorization pursuant to section 10 of the *HEEA*, which requires AUC approval for operation of a hydro development, the existing authorization to operate that power plant was properly granted pursuant to section 9 (now 11) of that Act. Therefore, the new authorization granted to ATCO Power (2010) Ltd., the AUC held, must also be granted under that section, i.e., Section 11 of the *HEEA*.

Summary

The AUC approved the Heartland Transaction and Oldman River Ownership Transfer.

NATIONAL ENERGY BOARD

Enbridge Pipelines Inc. Application for the Line 5 St. Clair River Replacement Project (NEB Hearing Order MHW-004-2019)

Pipeline Replacement Project - Public Interest

In this decision, the NEB determined that it was in the public interest to approve Enbridge Pipelines Inc. ("Enbridge")'s application to construct and operate the Line 5 St. Clair River Replacement (the "Project"), pursuant to section 58 of the *National Energy Board Act* ("*NEB Act*"). The NEB also approved the decommissioning of the existing segment of the Line 5 pipeline, pursuant to section 45.1 of the *National Energy Board Onshore Pipeline Regulations* ("*OPR*").

<u>Indigenous Matters</u>

The NEB found that Enbridge designed and implemented consultation activities that were appropriate for the size, scope, and scale of the applied-for Project.

The NEB found that Enbridge made reasonable opportunities available to Aamjiwnaang and other affected Indigenous communities to identify any concerns regarding Project impacts to traditional land and resource use. The NEB noted Enbridge's commitment to work with Indigenous communities to address any further concerns that may arise.

Adequacy of Crown Consultation

In *Clyde River (Hamlet) v Petroleum Geo-Services Inc.* and *Chippewas of the Thames First Nation v Enbridge Pipelines Inc.,* the Supreme Court of Canada acknowledged that the NEB has the procedural powers to implement consultation and the remedial powers to impose and enforce accommodation measures as well as the requisite technical expertise. The Supreme Court of Canada also acknowledged the Crown's ability to rely on the NEB's regulatory assessment process to fulfill its duty to consult. Under the *NEB Act* and caselaw, it was clear that the NEB was the final decision-maker in relation to this Project.

The NEB found that there was adequate consultation and accommodation for the purpose of the NEB's decision on the Project. The NEB also found that any potential Project impacts on the rights and interests of affected Indigenous communities were not likely to be significant and would be effectively addressed through conditions and commitments.

The NEB found that approval of this Project was consistent with section 35 of the *Constitution Act, 1982* and the Honour of the Crown.

<u>Public Consultation</u>

The NEB found that Enbridge adequately and appropriately identified stakeholders and potentially affected landowners, and developed appropriate engagement materials. The NEB found that Enbridge's design and implementation of consultation activities for the Project were appropriate given the scope and scale of the Project.

<u>Socioeconomic and Environment Matters</u>

The NEB found that the Project was not likely to result in significant adverse environmental or socioeconomic effects. The NEB found that Enbridge planned sufficient standard and site-specific measures to mitigate most of the potential adverse environmental effects identified.

<u>Engineering Matters</u>

The NEB found that the general design of the Project facilities was appropriate for the intended use, and that the facilities would be constructed in accordance with accepted standards for design, construction and operation.

The NEB was satisfied with the approach Enbridge proposed for crossing the St. Clair River, but noted that the success of horizontal directional drilling ("HDD") installations for pipeline construction depended on accurate HDD feasibility assessments, proper design and planning, and actual conditions encountered during the execution of the HDD. Therefore, the NEB imposed a condition requiring Enbridge to file a drilling execution plan.

<u>Economic Matters</u>

The NEB found that the project was economically feasible and the NEB did not have concerns with Enbridge's ability to finance the Project.

Findings

The NEB found that it was in the public interest to approve Enbridge's application to construct and operate the Project.

Jurisdiction over the Coastal GasLink Pipeline Project, (NEB Decision MH-053-2018)

Lack of Federal Jurisdiction Over Pipeline Project

In this decision, the NEB considered whether to assert jurisdiction over the Coastal GasLink Pipeline Project ("CGL Pipeline" or "Project").

The NEB concluded that the Project was not properly within federal jurisdiction, finding that:

(a) the Project did not form part of a single indivisible undertaking with the NOVA Gas Transmission Limited ("NGTL") System or any other federal undertaking under the first branch of the *Westcoast* test; and

(b) the Project was not essential, vital, or integral to a core federal work or undertaking under the second branch of the Westcoast test; and

(c) the Project was a local work and undertaking properly regulated by the Province of British Columbia ("BC").

Given this decision, the NEB refused to issue a declaratory order that the Project was subject to regulation by the NEB.

The Project

LNG Canada is a joint venture comprised of five companies (collectively, the "LNG Partners"): Shell (40 percent interest), North Montney LNG (25 percent interest), Diamond (15 percent interest), PetroChina (15 percent interest), and Kogas (5 percent interest). The LNG Partners were building an LNG export terminal to export liquified natural gas via tanker to international markets.

LNG Canada entered into a Project Development Agreement with TransCanada Pipelines Limited ("TCPL") to develop, build, own, and operate the CGL Pipeline, to transport natural gas from an area in BC near the gas supply of the LNG Partners to the LNG Terminal, in Kitimat BC. TransCanada PipeLines Limited ("TCPL") formed a wholly-owned subsidiary, CGL, to undertake the Project.

The Application for Review of Jurisdiction

On July 30, 2018, the NEB received an application from Mr. Michael Sawyer, requesting that the NEB, pursuant to subsection 12(1) of the *National Energy Board Act* ("*NEB Act*"), determine and issue a declaratory order that the CGL Pipeline was properly within federal jurisdiction and subject to regulation by the NEB.

The Project would be within federal jurisdiction if it formed part of a federal work or undertaking under section 92(10)(a) of the *Constitution Act, 1867*.

In its October 22, 2018 letter, the NEB indicated its usual practice for questions regarding jurisdictional matters is to first determine whether a *prima facie* case exists, such that setting down a full jurisdictional process would be warranted. The NEB determined that there was a *prima facie* case that the Project may form part of a federal undertaking on the basis of an indication of functional integration and common management, control, and direction of the CGL Pipeline and the existing federally regulated NGTL natural gas system ("NGTL System"). Like CGL, NGTL was a wholly-owned subsidiary of TCPL, which was in turn a wholly-owned subsidiary of TransCanada Corporation ("TCC").

The Board therefore decided to hold a process to fully consider the jurisdictional matter.

Jurisdictional Analysis

Summary of the legal test under section 92(10)(a) of the Constitution Act, 1867

In *United Transportation Union v Central Western Railway Corp.* the Supreme Court of Canada set out a two-branch framework that described the manner in which federal jurisdiction could be established under section 92(10)(a) of the *Constitution Act, 1867*, either directly (first branch) or derivatively (second branch), stating as follows:

> There are two ways in which Central Western may be found to fall within federal jurisdiction (…). First, it may be seen as an interprovincial railway and therefore come under s. 92(10)(a) of the *Constitution Act, 1867* as a federal work or undertaking. Second, if the appellant can be properly viewed as integral to an

> existing federal work or undertaking it would be subject to federal jurisdiction under s. 92(10)(a). …For the former, the emphasis must be on determining whether the railway is itself an interprovincial work or undertaking. Under the latter, however, jurisdiction is dependent upon a finding that regulation of the subject matter in question is integral to a core federal work or undertaking.

The two-branch test from *Central Western* was affirmed and further refined by the Supreme Court of Canada in *Westcoast Energy Inc. v. Canada (National Energy Board)* (the "*Westcoast* test").

Some of the key indicia described by the majority in *Westcoast* regarding a potential finding of direct jurisdiction (first branch) are as follows:

> … [T]he primary factor to consider is whether the various operations are functionally integrated and subject to common management, control and direction. The absence of these factors will, in all likelihood, determine that the operations are not part of the same interprovincial undertaking, although the converse will not necessarily be true. Other relevant questions, though not determinative, will include whether the operations are under common ownership (perhaps as an indicator of common management and control), and whether the goods or services provided by one operation are for the sole benefit of the other operation and/ or its customers, or whether they are generally available.

First branch of the Westcoast test – Is the CGL Pipeline part of a federal work or undertaking?

The NEB emphasized that determination under section 92(10)(a) of the *Constitution Act, 1867*, must be made on the factual circumstances of the particular case.

The NEB found that the facts did not support a finding that the CGL Pipeline was or could reasonably be expected to become functionally integrated with the NGTL System as part of a single interprovincial TCC undertaking. Rather, the CGL Pipeline was designed primarily to serve the interests of the LNG Partners, and not those of TCC or its affiliates. In the NEB's view, these underlying interests were evident in the structural differences between the CGL Pipeline and the NGTL System. The NEB found that the two systems did not share a common purpose and they were not dedicated to, dependent on, or interdependent of each other. Rather, they would function as separate enterprises, with separate business models. Despite a probable physical connection and the related potential for a commercial relationship, the two systems were not functionally integrated.

The NEB found that the overlap of many directors and officers and overlap regarding items such as websites, manuals, annual reports, and financial statements suggested some level of common management, control, and direction. However, the structure of the NGTL Code of Conduct and the fact that CGL (rather than TCPL) would operate the CGL Pipeline, and would have its own dedicated field staff, provided some separation in the management, control, and direction by TCC and its affiliates over the CGL Pipeline. However, more significantly, was the evidence regarding the substantial control and direction of LNG Canada and the LNG Partners over the design, construction, day-to-day operation, access to the capacity, and potential expansion of the CGL Pipeline.

The NEB found that the LNG Partners first exerted significant control and provided significant direction through the tender request for proposal process for a pipeline to transport natural gas from an area near the gas supply of Shell and its joint venture partners to the then-proposed LNG Terminal. While TCPL (through CGL) was chosen to provide transmission pipeline service through the CGL Pipeline, LNG Canada and the LNG Partners retained significant control and the ability to provide significant direction throughout the pipeline's construction and operations phases. This was completely distinct from the NGTL System, which was wholly under the management, control, and direction of NGTL and its corporate affiliates. The substantial level of control and direction of LNG Canada and the LNG Partners is was key consideration in the Board's conclusion that the CGL Pipeline and NGTL System were not subject to common management, control, and direction as part of some larger TCC undertaking.

Second branch of the Westcoast test – Is the CGL Pipeline integral to a federal work or undertaking?

The NEB explained that derivative jurisdiction under the second branch of the *Westcoast* test was dependent upon a finding that the provincial work or undertaking at issue was essential, vital, or integral to a core federal work or undertaking.

The NEB noted that in the case of *Tessier*, the Supreme Court of Canada provided its summary of the standard under the second branch of the *Westcoast* test as follows:

> In short, if there is an indivisible, integrated operation, it should not be artificially divided for purposes of constitutional classification. Only if its dominant character is integral to a federal undertaking will a local work or undertaking be federally regulated.

The NEB found that based on the evidence in this proceeding, it could not conclude that the NGTL System was dependent on the CGL Pipeline in any way. The operation of the NGTL System would not be affected if and when the CGL Pipeline connected to it. The NGTL System would continue to function as it currently does, as an integrated natural gas gathering and transmission network, irrespective of whether a connection was ultimately made to the CGL Pipeline. Therefore, the NEB concluded that the CGL Pipeline was not essential, vital, or integral to the NGTL System under the second branch of the *Westcoast* test.

Conclusion

The NEB concluded that the Project was not properly within federal jurisdiction. This was on the basis that the CGL Pipeline did not form part of a single indivisible undertaking with the NGTL System or any other federal undertaking under the first branch of the *Westcoast* test. The CGL Pipeline was likewise not essential, vital, or integral to a core federal work or undertaking under the second branch of the *Westcoast* test. The Project was a local work and undertaking properly regulated by the province of BC.

Given the Board's decision, the NEB refused to issue a declaratory order that the Project is properly within federal jurisdiction and subject to regulation by the NEB.